BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

In the Matter of	)	
	)	
PUBLIC UTILITIES COMMISSION	)	Docket No. 2008-0274
	)	
Instituting a Proceeding to Investigate	)	
Implementing a Decoupling Mechanism	)	
for Hawaiian Electric Company, Inc., and	)	
Hawaii Electric Light Company, Inc., and	)	
Maui Electric Company, Limited.	)	
	)	

HAIKU DESIGN AND ANALYSIS

FINAL STATEMENT OF POSITION

AND

CERTIFICATE OF SERVICE

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HAIKU DESIGN AND ANALYSIS

FINAL STATEMENT OF POSITION

Carl Freedman, dba Haiku Design and Analysis (HDA) respectfully offers its Final Statement of Position (FSOP) regarding the implementation a decoupling mechanism for the Hawaiian Electric Company. Inc., Maui Electric Company Ltd. and the Hawaii Electric Light Company, Ltd. (collectively: HECO Companies). HDA's FSOP differs from its Opening Statement of Position in several respects including several changes and refinements resulting from discussions at the Technical Workshops, discussions with the parties and further analyses by HDA. HDA looks forward to further constructive examination of the issues at the Panel Hearings and will make its final determination of position on the issues in its briefs in this docket.

TERMINOLOGY

(1) In order to clarify and distinguish several types of mechanisms considered in this "decoupling" docket, HDA refers distinctly to several types of mechanisms proposed in this docket:

- A "decoupling mechanism" is the specific mechanism designed to adjust revenues to make utility earnings indifferent to changes in sales or demand volume in periods between rate cases.
- A "revenue adjustment mechanism" (RAM) or "recoupling mechanism" is a mechanism to adjust target net revenues (usually intended to cover fixed costs) to account for non-sales or demand factors in periods between rate cases.
- A "revenue balancing account" (RBA) is a cost accounting, adjustment and reconciliation mechanism used to implement one or both of the above mechanisms.

OVERVIEW

HDA supports the implementation of a decoupling mechanism for the HECO Companies that effectively insulates the utilities' earnings from fluctuations in sales volumes in years between rate cases. HDA recommends several modifications or alternative components to the mechanisms proposed by the HECO Companies. Each of the following specific recommendations is explained in more detail below:

- HDA withdraws its proposed marginal price formula decoupling mechanism described in its "HDA example mechanism" in previous filings.

- HDA supports the revenue balancing account (RBA) decoupling mechanism proposed by the HECO Companies with some modifications. In particular, the effects of the Energy Cost Adjustment Clause (ECAC) mechanisms on the proper functioning of the decoupling mechanisms need to be addressed.
- HDA supports consideration of a "revenue per customer" approach to "recoupling" as an alternative to the HECO Companies' proposed RAM.
- HDA remains open and looks forward to examining any specific proposals by the other parties that may be put forward in the FSOP's.
    - Alternative mechanisms to reconcile the HECO Companies' ECAC mechanisms with the proposed decoupling mechanisms.
    - Performance indices that would be used in conjunction with the proposed RAM to promote implementation of HCEI goals and/or to ensure maintenance of adequate service quality.
- HDA offers several observations for consideration.
    - HECO's ability to go three years between rate cases in current regulatory environment (without sacrificing service quality).

GENERAL POSITION

(1) HDA supports the implementation of a decoupling mechanism for the HECO Companies that effectively insulates the utilities' earnings from fluctuations in sales volumes in years between rate cases. Effective decoupling would provide several benefits. Of primary importance to HDA in this docket, a decoupling mechanism would decrease existing disincentives for the utilities to embrace programs (by the utilities or other parties) that reduce energy consumption including energy efficiency programs and customer sited renewable generation.

SPECIFIC RECOMMENDATIONS

(2) HDA withdraws its proposed marginal price formula decoupling mechanism described in its "HDA example mechanism" in previous filings.

HDA proposed a decoupling mechanism (HDA example mechanism) "for purposes of discussion and consideration" in its Responses to the National Regulatory Research Institute (NRRI) Appendix 2 Questions for the Parties, question number 2. HDA reaffirmed this proposal in its Opening Statement of Position (OSOP).

One reason for proposing the HDA example mechanism was to "engage a meaningful discussion of the initial and ongoing determination of fixed and variable costs and the relationship between average variable costs determined in the context of a rate case and the import of considering short run marginal costs in the context of application of a decoupling mechanism." (HDA Responses to NRRI Appendix 2 at pages 4 – 5) One reason for withdrawing the HDA example mechanism from further considerations is that, after engaging in fruitful discussion and analysis of these issues, HDA determined that the marginal price formula approach proposed in the mechanism is not correct because it is not consistent with the HECO Companies' ECAC reconciliation mechanisms.[1] HDA also

[1] Both the HDA example mechanism and the HECO proposed decoupling mechanism are inaccurate regarding interactions with the existing HECO ECAC Companies' ECAC reconciliation mechanisms. This matter, as it pertains to the HECO proposed mechanism, is discussed in detail below.

believes that an RBA accounting method is better than a price formula because it provides more transparency and flexibility.[2]

(3) HDA supports the revenue balancing account (RBA) decoupling mechanism approach proposed by the HECO Companies with some modifications. The HECO proposed decoupling mechanism and RBA accounting approach attempt to accomplish the same result as the previously proposed HDA example mechanism. This is an earnings decoupling mechanism intended to make the HECO Companies ambivalent (from the standpoint of net earnings) to fluctuations in electricity sales volumes in the years between rate cases. Some modification is necessary in order to address the interaction of the companies' ECAC mechanisms in order to properly decouple sales volumes from earnings. This is discussed below.

(4) The effects of the Energy Cost Adjustment Clause (ECAC) reconciliation mechanisms on the proper functioning of the decoupling mechanisms need to be addressed. HDA previously raised questions and concerns regarding the accuracy of some components of HECO's proposed decoupling mechanism. HDA questioned the relationship between the proposed HECO decoupling mechanism and (a) the treatment of fuel and purchased energy costs and how these are combined or differentiated from fixed costs in base rates, (b) changes in actual fuel and purchased energy costs resulting from changes in

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[2] HDA originally proposed its example mechanism on behalf of a party in a previous docket in which it was the sole proponent of implementing decoupling. The example mechanism was designed to look and operate as much as possible in a manner similar to the existing ECAC mechanisms (a price adjustment formula approach) in order to be as simple and as familiar as possible to HECO and the other parties in that docket. An RBA approach is a more substantial proposal for an additional regulatory process but is more straightforward and provides more transparency and accountability.

sales volume, (c) actual revenue streams collected by various tariffs and surcharges and (d) adjustments and reconciliations made by other existing and proposed mechanisms. In particular, HDA originally asserted that it was necessary to use marginal fuel and purchased energy costs rather than average test year fuel and purchased energy costs in calculating the portion of actual revenue streams available to the company to meet the "fixed" revenue targets in the proposed mechanism. In response to HDA's initial presentation of these assertions at the first technical workshop in this docket (February 27, 2009), it was suggested by HECO and Consumer Advocate representatives that the ECAC reconciliation process should address the concerns regarding marginal versus average costs raised by HDA. HDA followed up on the first workshop presentation with several discussions with other parties and an analysis of the interaction of HECO's existing ECAC reconciliation mechanism with the HDA and HECO proposed decoupling mechanisms. The analysis approach uses the two completely configured "cases" in HECO's pending 2009 test year rate case (the direct case and the update case). Since these two "cases" differ essentially only in the level of sales assumed, they present a propitious opportunity to examine the efficacy and accuracy of the proposed decoupling mechanisms.

HDA's initial "two-case" analysis was presented (before completion) and explained in HDA's Attachment 2 and response to question number 24 of the information requests transmitted by the Commission to the parties in this docket on March 5, 2009. As explained in its response to question 24, the initial analysis in the response Attachment 2 "does not take into account several factors, such as the existing ECAC reconciliation adjustments, that are ultimately necessary to consider in evaluating the proposed decoupling mechanisms." The initial analysis was presented prior to completion at the time of the information requests to "demonstrate the nature of the concerns expressed by HDA at the February 13, 2009 technical conference (prior to any consideration of the effects of existing ECAC reconciliations)" and to "show that the information provided in HECO's pending rate case provides a propitious opportunity to examine and demonstrate the workings, accuracy and efficacy of any proposed decoupling mechanisms."

After further discussion with HECO regarding the ECAC methodology HDA completed its two-case analysis. This analysis was presented and explained at the second technical workshop in this docket (April 20, 2009) followed by yet further discussion with HECO and the Consumer Advocate (and one correction to the HDA analysis). The completed (and corrected) analysis is attached to this FSOP as Exhibit A.[3]

Page one of Exhibit A is the initial HDA two-case analysis previously provided in response to question 24 discussed above. This analysis is not correct because it does not consider the effects of the HECO ECAC reconciliation on company revenues. See HDA response to question 24 for an explanation of the analysis.

Page two of Exhibit A shows the results of the completed analysis taking into account the ECAC reconciliation. This analysis indicates that, if the direct case assumptions were used to determine HECO's rates and the update case assumptions actually occurred in the following year (a decrease in sales volume of 173.1 GWH), HECO would have a net shortfall of approximately $16 million in revenues available to meet its fixed costs (result at line N) without any decoupling mechanism. With HECO's proposed adjustment mechanism HECO would have a surplus of approximately $1 million (result at line T). With HDA's previously proposed mechanism (unmodified to account of the ECAC reconciliation) HECO would have a shortfall of approximately $8 million (result at line Y).

Page 3 of Exhibit A shows the ECAC reconciliation page from a recent HECO ECAC filing. Pages 4 through 8 of Exhibit A show the steps and calculations used in the HDA two-case analysis as explained by HDA at the second technical workshop.

The following statements appear to HDA to be generally agreed by all parties in the discussions:

- The existing ECAC reconciliation mechanisms fully reconcile revenues collected for purchased energy expenses with actual purchased energy expenses. Actual purchased energy expenses are passed straight through to customers via the quarterly and annual ECAC reconciliation mechanisms.
- The existing ECAC reconciliation mechanism does not fully reconcile the HECO Companies' actual generation expenses with actual revenues. Instead, revenues are reconciled to a target "Fuel Filing Cost" calculated by a formula assuming a fixed sales heat rate determined in the most recent previous rate case.[4] The existing ECAC

[3] The correction was to the sales heat rate entered on line 19 of page 7 of HDA FSOP Exhibit A (attached). Other than labeling, this correction is the only difference between Exhibit A and the exhibit distributed and presented at the second technical workshop.

[4] The Fuel Filing Cost is shown at lines 5 through 8 on the example HECO ECAC reconciliation filing provided as page 3 of HDA FSOP Exhibit A (attached). Note that the target costs to which revenues are reconciled for generation (line 5) and DG Power (line 7) are different than the actual recorded expenses for these components (lines 1 and 3).

method explicitly adjusts for actual versus test year fuel prices, actual versus test year generation fuel mix and actual versus test year proportions of company generation versus purchased energy. The mechanism (including reconciliation) deliberately does not adjust for or reconcile to actual generation fuel expenses in order to leave an incentive to the HECO companies to generate energy efficiently (from a thermodynamic standpoint in terms of maximizing kWh per BTU of fuel consumed). If a company generates electricity with fewer BTU's than assumed in the test year fixed sales heat rate it will come out ahead financially (and visa versa).

- The volume of electricity sales affects the efficiency of company generation. This is clearly demonstrated by the fact that the sales heat rate calculated by HECO for the direct case is higher (less efficient) than the sales heat rate in the updated case in which the only pertinent difference is the assumed level of sales.[5]

In addition, HDA asserts (and has heard no arguments to the contrary from any of the other parties in the discussions) that:

- The HDA analysis demonstrates that a difference in the volume of sales, even after ECAC adjustment and reconciliation, affects utility earnings and is not completely and properly accounted for by either the HDA or HECO proposed decoupling mechanisms.
- In the context of the implementation of HECO's proposed decoupling mechanism as applied to HECO, the existing ECAC reconciliation mechanism properly accounts

for most, but not all, of the discrepancy originally asserted by HDA resulting from using average test year costs (rather than marginal costs as HDA originally asserted should be used) in determining the portion of the stream of actual revenues that is applied to the fixed cost target. In other words, with the existing ECAC reconciliation method, the HECO proposed decoupling method comes close to but does not exactly decouple earnings from fluctuations in sales volume. The HDA analysis indicates that the HECO decoupling mechanism would "over-decouple" earnings by $1.1 million to $1.3 million as a result of the 173.1 GWH difference in sales volume between the direct and update test year cases.[6] HDA notes that the magnitude of the remaining discrepancy could be substantially different for the MECO or HELCO systems or in different circumstances than assumed in the test year assumptions.

- HDA's analysis indicates that, if the HECO Companies' ECAC reconciliation mechanisms were changed to fully pass through and reconcile actual revenues to actual generation expenses, the HECO proposed decoupling mechanism would produce accurate results and properly decouple HECO's earnings from fluctuations in sales volumes.

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[5] The sales heat rates were calculated by HECO for both the direct and update cases using a production simulation model that calculates the operation, dispatch and fuel consumption of each generation resource for each set of test year assumptions (direct case at 11,185 mbtu/mwh; update case at 11,166 mbtu/mwh).

[6] The HDA analysis calculates the accuracy of the decoupling adjustments using two alternate approaches. According to tabulation of revenues and expenses from the direct and update rate case filings, as shown on line T of page 2 of Exhibit A, the calculated decoupling error is $1,072,780. According to tabulation of revenues and costs based on price and sales volume calculations using the ECAC reconciliation format, as shown on line L of page 8 of Exhibit A, the calculated decoupling error is $1,322,000.

(5) The effects of the Energy Cost Adjustment Clause (ECAC) reconciliation mechanisms on the proper functioning of the decoupling mechanisms could be addressed in any of several ways. HDA remains open to various approaches to addressing this issue and frames the following options for purposes of further consideration:

(a) The HECO Companies' decoupling mechanism could be implemented as proposed without any change to the existing ECAC mechanism. This approach would not produce results that are theoretically or exactly correct but, at least as has been demonstrated by HDA in the instance of the HECO generation system and current circumstances, would produce results that may be acceptable. This approach (even after application of HECO's proposed decoupling adjustment) would leave HECO with some residual incentive to reduce sales since earnings would be increased with reduced levels of sales. It would remain to be tested whether this approach would be acceptable for the MECO and HELCO systems or for the HECO system in substantially different circumstances.

(b) The HECO Companies' decoupling mechanism could be implemented along with changing the ECAC reconciliation to a full pass through of actual generation expenses. This would result in accurate earnings decoupling but would remove an existing incentive in the current implementation of the ECAC that encourages the companies to operate their systems in an efficient manner. Several arguments are considered below:

- A straight cost pass through would considerably simplify administration of the fuel adjustments and the decoupling mechanisms. First, it is very simple compared to the existing ECAC. Second, it would simplify the administration of a decoupling mechanism. In fact, if there is going to be a revenue balancing account (RBA) for the decoupling mechanism, implementing a straight pass through could be done as part of the same set of calculations, adjustments and reconciliations. One set of lines in the RBA would match and adjust collected revenues for fixed costs to target revenues for fixed costs (the HECO proposed decoupling method). A second set of lines would match and adjust collected revenues for fuel and purchased energy to actual fuel and purchased energy expenses (a straight full cost pass through).[7]
- A straight pass through is consistent with the objectives of the RAM generally: reduction of risk and uncertainty in full recovery of utility expenses.
- The existing ECAC incentives to the utility to operate its system efficiently from a thermodynamic standpoint (to minimize system heat rate) provides some convoluted incentives regarding commitment of purchased power generation units versus commitment of company generation units.[8] A straight fuel cost pass through would "decouple" utility earnings from resource commitment (and curtailment) decisions. This could be especially important with the substantial amounts of new renewable generation expected to be added to the utility systems. The utility should not be at

[7] This would effectively be the same as reconciling collection of revenues to line 1 rather than line 5 of the HECO ECAC reconciliation procedure shown on page 3 of Exhibit A (attached).

financial risk for resource commitment and curtailment decisions that should be made according to policies (maximization of renewable generation) that may conflict with the most efficient thermodynamic operation of the utilities' own generation units.

- Similarly, the existing ECAC provides an incentive for the utilities to minimize operation reserve capacity and, in effect, penalizes utility earnings for providing additional operation reserve capacity. This is significant because maximizing the incorporation of intermittent renewable resources requires providing increased operating reserve capacity. The utilities should not be financially penalized for providing ample operation reserves in order to accommodate intermittent renewable generation. A straight fuel cost pass through would "decouple" utility earnings from operation reserve capacity decisions.
- Since the HECO Companies currently dispatch generation resources using AGC controls that are based on minimizing economic costs, regulators have a simple verifiable way to determine that resources are being operated economically. The efficiency incentive in the existing ECAC is not necessary to ensure economic dispatch of system resources.[9]

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[8] Commitment refers to the decisions made by a utility dispatcher to start generation units or take units off-line in order to maintain sufficient operating generation units to meet instant generation requirements and necessary operating reserves.

[9] Note that the utilities actually do not really dispatch resources directly according to ECAC revenue maximization in any case since resources are dispatched based on minimizing fuel expense, not based on minimizing BTU consumption.

- One argument against a full cost pass through is that the existing ECAC mechanism provides an incentive for the utility to diligently maintain its generation units to maximize unit availability, minimize unit forced outage and to schedule planned maintenance outages prudently. Converting the ECAC to a full cost pass through would eliminate these beneficial incentives.
- The fact that the existing ECAC mechanism includes an efficiency incentive is recognized as an asset in defense of the ECAC in recurrent discussions (before the legislature and in the press) regarding proposals to eliminate the ECAC entirely.

(c) The HECO Companies' decoupling mechanism could be implemented along with changing the ECAC reconciliation to incorporate a full pass through of actual generation expenses only within a prescribed "deadband" range of system efficiency with existing incentives applied outside the prescribed range. This approach was outlined in principle in discussions that included HDA, HECO and the Consumer Advocate. This approach would attempt to retain the efficiency incentives of the existing ECAC while allowing full cost pass through within a reasonable range. A detailed proposal has not been resolved. HDA remains open to further discussion regarding this approach as may be proposed in other parties' FSOP's or during the interim period before the Panel Hearings in this docket.

(d) The HECO Companies' decoupling proposal could be implemented with an adjustment factor to correct for ECAC reconciliation residual effects. This approach would require determination, in a rate case, of the sensitivity of the utility system efficiency to fluctuations in sales volume to determine a coefficient or adjustment factor to be applied in determining the generation expense component of fuel and purchased energy revenues that are netted out of the revenue cost stream counted towards the "fixed" revenue decoupling target. This approach would leave the existing ECAC reconciliation mechanism unchanged. HDA has not discussed this approach with other parties.

(6) HDA supports consideration of a "revenue per customer" (RPC) approach to "recoupling" as an alternative to the HECO Companies' proposed RAM.

HDA proposed using a modified revenue per customer index as a "recoupling" mechanism in its "HDA example mechanism" proposed in previous filings. Although HDA is withdrawing its HDA example mechanism proposal it notes that the RPC index component of the HDA example mechanism could be applied in conjunction with the HECO Companies' decoupling proposal as part of the RBA accounting approach. Noting also that the parties in this docket who are signatories to the October 2008 "HCEI" Agreement (the HECO Companies, Consumer Advocate and DBEDT) are not permitted by the terms of the Agreement to propose a mechanism indexed on the number of customers, HDA proposes an RPC mechanism here for consideration in this docket.

HDA proposes an RPC approach in this docket in order to provide at least one decoupling and recoupling mechanism in this proceeding that (a) is simple and certainly feasible to administer and (b) is designed exclusively to effectively decouple earnings from sales volume while generally preserving, rather than substantially enhancing, the value of the revenue stream to the utility between rate cases.[10]

HDA's proposed RPC index approach is explained generally in HDA's response to the NRRI scoping paper Appendix 2 question number 2. A numerical example of the application of the approach that could be applied directly to HECO's proposed RBA accounting mechanism is shown on the bottom half (lines G through M) of page 4 of HDA Attachment 2, HDA Responses to NRRI, February 19, 2009, filed in this docket.

Application of the RPC index in conjunction with HECO's proposed decoupling mechanism and RBA accounting approach could be as follows:

The RPC index is designed to allow recovery of test year fixed costs to grow in proportion with utility system growth using an index of the number of new customers as a proxy for utility system growth between rate cases.

- For purposes of implementing the decoupling mechanism, the index of the number of customers would not be the same as the number of accounts. The number of customers used as an index in the mechanism is intended to serve as a proxy for the amount of growth on the utility system. In order to serve this specific purpose simply, without opportunity for gaming or spurious circumstances, the following conventions are suggested.

[10] The RPC mechanism neither presumes nor is intended to provide completely accurate recovery of the utility's actual fixed costs that are incurred in the intervals between rate cases. The existing tariffs do not accurately recover utility fixed costs between rate cases. The proposed RPC mechanism does not attempt to "fix" or improve all aspects of the accuracy of the existing regulatory compact.

- For each customer class group the index of the number of customers would be equal to the test year number of customers plus the number of new customers at new premises. Ordinarily a building permit would be associated with each new customer.
- Expiring customer accounts would not reduce the index of the number of customers[11] and new accounts at premises that previously received service would not be added.
- Accounts generated by converting master metered buildings to individually metered accounts (or vice versa) would not change the index of the number of customers.
- Customers moving from one customer class to another should be treated according to a reasonable convention that could be discussed.

- As proposed by HECO, the decoupling mechanism would apply only to two customer class groups (residential and commercial). As proposed here there would be three customer groups (residential, commercial-without-schedule-P and Schedule P).
    - The RPC index would be applied to the residential and commercial-without-schedule-P class groups to escalate target revenues for fixed costs for these groups.

[11] This is consistent with a premise that utility fixed costs do not decrease (in a one to three year time frame) if a customer disconnects or leaves the system.

- The RPC index would not be applied to the Schedules PT, PP and PS since these classes are already essentially "decoupled" by way of marginal revenues being approximately the same as marginal energy delivery costs. Fixed costs are almost completely embedded in demand charges which would grow (even without RPC adjustment) in proportion with the number and size of new customers. It is difficult to effectively apply an RPC index to Schedule P customers in any case since the average size of customers is large, quite variable and the number of customers is relatively small.
- Schedule F is ignored since it comprises only a small fraction of HECO's energy revenues.

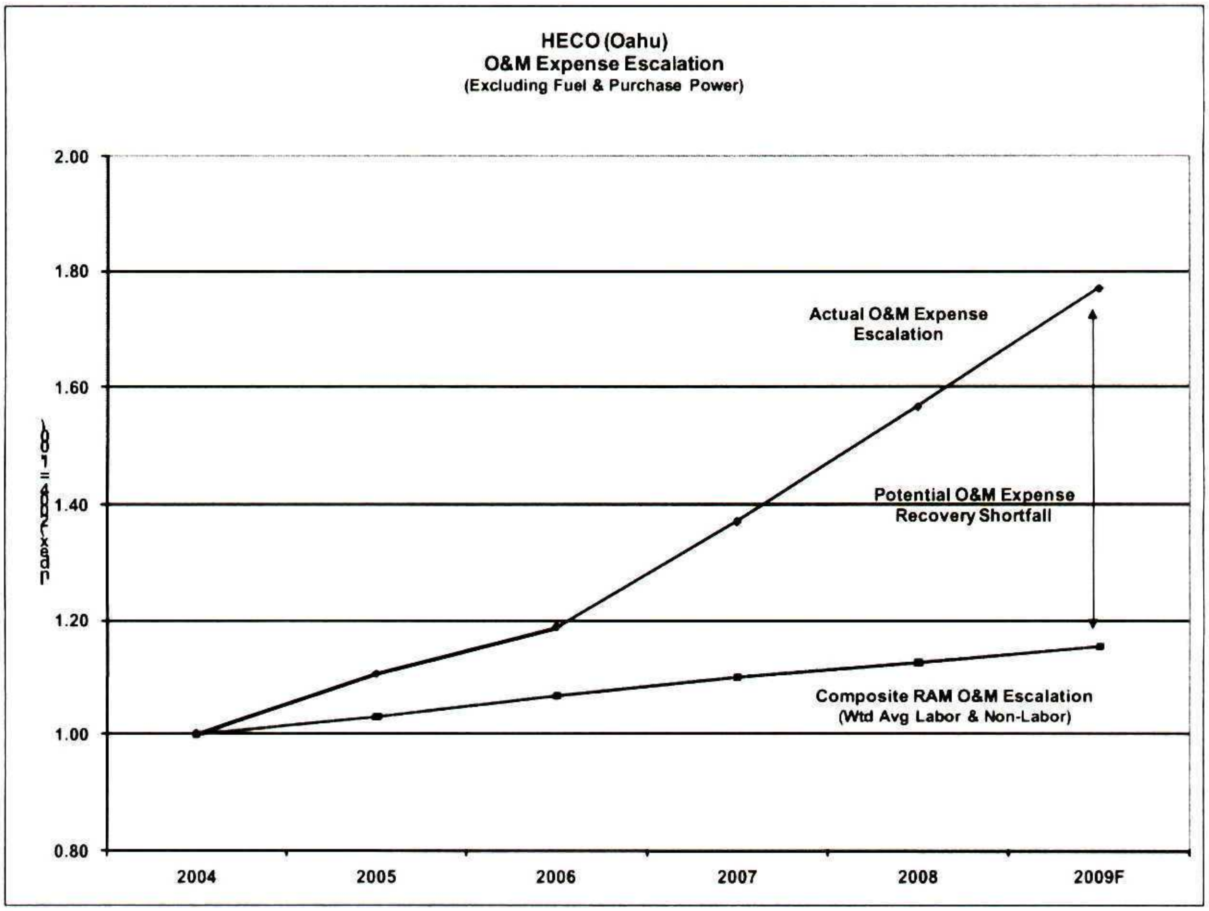
(7) HDA supports the ROE sharing mechanism proposed by the Consumer Advocate in this proceeding. The potential size of annual decoupling and RAM annual rate increases could be significant due to recent and anticipated declines in sales volume and the potential for future inflationary pressures.

(8) HDA remains open and looks forward to examining any specific proposals by the other parties that may be put forward in the FSOP's. These might include:

- alternative mechanisms to reconcile the HECO Companies' ECAC mechanisms with the proposed decoupling mechanisms
- performance indices that would be used in conjunction with the proposed RAM to promote implementation of HCEI goals and/or to ensure maintenance of adequate service quality.

OBSERVATIONS FOR CONSIDERATION

(9) Unless HECO is able to significantly reduce recent trends in annual O&M expense escalation, it is probable that HECO would have to file a general rate case more frequently than every three years. HECO's recent O&M expense escalation substantially exceeds the estimates of anticipated RAM adjustments in the examples provided by HECO in this docket.[12] This is shown graphically in the chart below.



[12] Annual O&M expenses, excluding fuel and purchased power, have increased at a compound annual growth rate of 11.4% from 2003 – 2008. HECO has stated publicly that it expects 2009 O&M expenses to increase 13% over the 2008 actual level. Without Customer Service expenses (which include DSM program expenses) O&M expenses increased at a compound annual growth rate of over 9% from 2003 – 2008.

HECO's rapidly escalating operating expenses and significant annual capital spending in the face of declining electric sales volumes represent major cost management and financial challenges for HECO and its customers. It also presents major regulatory challenges for the PUC. For customers, it suggests that significant future base rate increases may be likely. For HECO, it suggests a pressing need for significant cost management efforts to reduce O&M cost increases in order to earn authorized returns without frequent rate cases. This situation existed prior to the HCEI Agreement but may only be furthered by the anticipated capital and resource costs of the initiatives identified in the Agreement.

HECO could take measures to significantly reduce O&M expenses in the future in order to bring annual O&M spending in line with authorized revenues (whether determined by the proposed RAM or not). How this would be accomplished is critical. From a regulatory standpoint it is important to ensure that significant reductions in O&M are accomplished in a manner that does not adversely affect customer service quality and reliability. A possible solution to this concern would be to incorporate a service quality incentive mechanism as part of any RAM adjustment. HECO previously proposed a Service Quality Mechanism in an application to the Commission to implement performance based ratemaking (PBR) in Docket No. 99-0396.[13] HECO's Service Quality Mechanism was an integral part of its PBR proposal to ensure service quality in conjunction with the institution of O&M rate indexing (similar to what is proposed in HECO's RAM in the

[13] The proposed mechanism would include a System Average Interruption Frequency Index, a System Average Interruption Duration Index and measures of telephone call response time and customer satisfaction surveys. Financial penalties and rewards would be implemented if the indices exceeded or fell short of a "deadband" of acceptable performance.

instant docket). In its PBR application HECO states that service quality incentives "can be especially effective in creating countervailing incentives to maintain or improve quality levels when managers have stronger incentives to control costs." (PBR Application at page 18, Docket No. 99-0396).[14] The Service Quality Mechanism proposed by HECO in its PBR application could be implemented independently or as part of the RAM mechanism in this docket.

(10) Decoupling and RAM mechanisms should reduce HECO's regulatory risks by reducing regulatory lag and providing the potential for more annual rate increases without traditional rate case prudency reviews of various components of revenue requirements. In addition, decoupling shifts the financial risks associated with fluctuations in sales volume due to weather, business cycles or customer price responses from utility shareholders to utility customers. This reduction in HECO's regulatory and financial risk should be considered in establishing the allowed return on equity in the current and future rate cases.

CONCLUSION

HDA looks forward to the FSOP's filed by other parties in this docket and intends to work with the other parties to resolve constructive solutions to the remaining issues.

Dated: May 9, 2009; Haiku, Hawaii

Signed: CARL FREEDMAN

Carl Freedman

[14] The Commission dismissed HECO's PBR application without prejudice in Order No. 18353 dated February 2, 2001.

Decoupling Example Comparison Worksheet

Original HDA Exhibit - No Accounting of ECAC
Assumes Direct Case Is Test Year Basis for Determining Rates and Update Case Occurs in Following Year

Line			Direct	Update	Increment
A	Total Fuel Expense	HECO T-4 2 of 121 (Update)	$816,654,000	$784,033,000	-$32,621,000
B	Purchased Energy Expense	HECO-601 (Update)	$369,123,533	$366,938,695	-$2,184,838
C	Total Fuel and Purch Energy	(A+B)	$1,185,777,533	$1,150,971,695	-$34,805,838
D	TY Non Fuel/Purch Energy (Fixed)	Approximate for Example	$750,000,000	$750,000,000	$0
E	Example Test Year Rev. Requirement	(C+D)	$1,935,777,533	$1,900,971,695	-$34,805,838
F	Test Year Sales	HECO T-4 2 of 121 (Update)	7657.8	7484.7	-173.1
G	Total Average Rate $/MWH	(E*.001/F)	$252.79	$253.98	
H	Average Rate Fuel and Purch Energy	(C*.001/F)	$154.85	$153.78	$201.07
J	Average Rate Non-Fuel & Penergy	(D*.001/F)	$97.94	$100.20	
IF RATES ARE BASED ON DIRECT CASE BUT UPDATE SALES ACTUALLY OCCURS					
K	Actual Revenues	(G from Direct * F from Updated)		$1,892,020,437	-$43,757,096
L	Fuel and Purch Energy Expense	(C)		$1,150,971,695	
M	Net to Cover Fixed Costs	(K - L)		$741,048,742	
N	Revenue Surplus (+) or Shortfall (-)	(M - D)		-$8,951,258	
HECO DECOUPLING ADJUSTMENT					
P	Revenue Target	(D)		$750,000,000	
Q	Actual Revenue Applied to Target	(F from Update * J from Direct)		$733,046,697	
R	HECO Decoupling Adjustment	(P - Q)		$16,953,303	
S	Net to Cover Fixed Costs	(K + R - L)		$758,002,044	
T	Revenue Surplus (+) or Shortfall (-)	(S - D)		$8,002,044	
HDA DECOUPLING ADJUSTMENT					
U	Short Run Marginal Energy Cost	(H Incremental = C*.001/F)	$201.07		
V	Fixed Margin	(G from Direct - U)	$51.71		
W	Decoupling Adjustment	(F Increment * V from Direct)		$8,951,258	
X	Net to Cover Fixed Costs	(K + W - L)		$750,000,000	
Y	Revenue Surplus (+) or Shortfall (-)	(X - D)		$0	

Decoupling Example Comparison Worksheet

Assumes Direct Case Is Test Year Basis for Determining Rates and Update Case Occurs in Following Year
Includes ECAC Adjustment Revenues With Annual Reconciliation

Line			Direct	Update	Increment
A	Total Fuel Expense	HECO T-4 2 of 121 (Update)	$816,654,000	$784,033,000	-$32,621,000
B	Purchased Energy Expense	HECO-WP-1036, p6	$317,211,700	$315,032,000	-$2,179,700
C	Total Fuel and Purch Energy	(A+B)	$1,133,865,700	$1,099,065,000	-$34,800,700
D	TY Non Fuel/Purch Energy (Fixed)	Approximate for Example	$750,000,000	$750,000,000	$0
E	Example Test Year Rev. Requirement	(C+D)	$1,883,865,700	$1,849,065,000	-$34,800,700
F	Test Year Sales	HECO T-4 2 of 121 (Update)	7657.8	7484.7	-173.1
G	Total Average Rate $/MWH	(E*.001/F)	$246.01	$247.05	
H	Average Rate Fuel and Purch Energy	(C*.001/F)	$148.07	$146.84	$201.04
J	Average Rate Non-Fuel & Penergy	(D*.001/F)	$97.94	$100.20	
IF RATES ARE BASED ON DIRECT CASE BUT UPDATE SALES ACTUALLY OCCURS					
K	Base Revenues	(G from Direct * F from Updated)		$1,841,282,040	-$42,583,660
KA	ECAC Revenues	From Following Yr. Reconciliation		-$8,097,563	
KB	Total Revenues	(K + KA)		$1,833,184,477	
L	Fuel and Purch Energy Expense	(C)		$1,099,065,000	
M	Net to Cover Fixed Costs	(KB - L)		$734,119,477	
N	Revenue Surplus (+) or Shortfall (-)	(M - D)		-$15,880,523	
HECO DECOUPLING ADJUSTMENT					
P	Revenue Target	(D)		$750,000,000	
Q	Actual Revenue Applied to Target	(F from Update * J from Direct)		$733,046,697	
R	HECO Decoupling Adjustment	(P - Q)		$16,953,303	
S	Net to Cover Fixed Costs	(KB + R - L)		$751,072,780	
T	Revenue Surplus (+) or Shortfall (-)	(S - D)		$1,072,780	
HDA DECOUPLING ADJUSTMENT					
KB	Total Revenues (Including ECAC Adj.)	(KB)		$1,833,184,477	
L	Fuel and Purch Energy Expense	(L)		$1,099,065,000	
U	Short Run Marginal Energy Cost	(H Incremental = C*.001/F)	$201.04		
V	Fixed Margin	(G from Direct - U)	$44.96		
W	Decoupling Adjustment	(F Increment * V from Direct)		$7,782,960	
X	Net to Cover Fixed Costs	(KB - L + W)		$741,902,437	
Y	Revenue Surplus (+) or Shortfall (-)	(X - D)		-$8,097,563	

HAWAIIAN ELECTRIC CO., INC.
2008 FUEL OIL ADJUSTMENT RECONCILIATION SUMMARY
(Thousand $)

Line		4th Qtr Total	collectn by company*
	ACTUAL COSTS:		
1	Generation	856,990.0	
2	Purch Power	316,622.1	
3	DG Power	1,722.6	
4	TOTAL	1,175,334.7	
	FUEL FILING COST (1)		
5	Generation	863,762.7	
6	Purch Power	316,622.1	
7	DG Power	1,620.6	
8	TOTAL	1,182,005.4	
	BASE FUEL COST		
9	Generation	259,487.0	
10	Purch Power	182,184.6	
	DG Power	474.5	
11	TOTAL	442,146.1	
12	FUEL-BASE COST (Line 8-11)	739,859.3	
13	ACTUAL FOA LESS TAX	743,776.2	
14	FOA reconciliation adj for prior year	4,793.3	
15	ADJUSTED FOA LESS TAX	738,982.9	
16	FOA-(FUEL-BASE) (Line 15-12)	(876.4)	under
	ADJUSTMENTS		
17			
18	Current month's FOA adjustment in line 14	419.8	
19	DG Fuel & Trucking	-	
20	QUARTERLY FOA RECONCLTN (Line 14-15+16-17)	(456.5)	under
	EXPLANATORY ITEMS:		
21	Generation mix difference with actual	(338.0)	
22	Fuel factor difference with actual	28.4	
23	FOA reconciliation variance	(54.5)	
24	FOA Rev not returned to employees	(143.1)	
25			
26	TOTAL EXPLAINED	(507.2)	under
27	REMAINDER UNEXPLAINED	50.6	over

NOTES: 1. ACTUAL costs adjusted to reflect 11140 btu/kwh effective June 20, 2008.

* Over means an over-collection by the company.
Under means an under-collection by the company.

Hawaiian Electric Company, Inc.
ENERGY COST ADJUSTMENT FILING
Direct Case Assumed As Test Year To Establish Rates

Line			
1	**Effective Date**	2009 Test Year - Direct	
2	**Supercedes Factor**		
	GENERATION COMPONENT		
	FUEL PRICES, ¢/MBTU		
3	Honolulu	1,652.16	
4	Kahe	1,602.36	
5	Waiau-Steam	1,602.06	
6	Waiau-Waste	**0.00**	
7	Waiau-Diesel	2,366.04	
8	CIP-Diesel	2,402.08	
9	CIP-Biodiesel	4,643.68	
	BTU MIX, %		
10	Honolulu	4.03	
11	Kahe	69.33	
12	Waiau-Steam	25.12	
13	Waiau-Waste	0.00	
14	Waiau-Diesel	0.57	
15	CIP-Diesel	0.88	
16	CIP-Biodiesel	0.07	
		100.00	
17	COMPOSITE COST OF GENERATION, ¢/MBTU	1,617.81	
18	% Input to system kWh Mix	58.39	
19	Efficiency Factor, Mbtu/kWh	0.011185	
20	WEIGHTED COMPOSITE GEN COST, ¢/KWH (Line 17 x 18 x 19)	$\boxed{10.56579}$	18.10
21	BASE GENERATION COST, ¢/Mbtu	1,617.81	
22	Base % Input to System kWh Mix	58.39	
23	Efficiency Factor, Mbtu/kWh	0.011185	
24	WEIGHTED BASE GEN COST, ¢/KWH (Line 21 x 22 x 23)	$\boxed{10.56579}$	18.10
25	Cost Less Base (Line 20 - 24)	0.00000	
26	Revenue Tax Req Multiplier	1.0975	
27	GENERATION FACTOR, ¢/KWH (Line 25 x 26)	0.00000	
	DG ENERGY COMPONENT		
28	COMPOSITE COST OF DG ENERGY, ¢/kWh	24.99	
29	% Input to System kWh Mix	0.07	
30	WTD COMP DG ENRGY COST, ¢/KWH (Line 28 x 29)	$\boxed{0.01750}$	25.00
31	BASE DG ENERGY COMP COST	24.993	
32	Base % Input to System kWh Mix	0.07	
33	WTD BASE DG ENERGY COST, ¢/KWH (Line 31 x 32)	$\boxed{0.01750}$	25.00
34	Cost Less Base (Line 30 - 33)	0.00000	
35	Loss Factor	1.052	
36	Revenue Tax Req Multiplier	1.0975	
37	DG FACTOR, ¢/KWH (Line 34 x 35 x 36)	0.00000	
38	TOTAL GENERATION FACTOR ¢/KWH (Line 27 + 37)	0.00000	

Line				
	PURCHASED ENERGY COMPONENT			
	PURCHASED ENERGY PRICE - ¢/KWH			
39	THC	- On Peak		20.440
40		- Off Peak		14.990
41	HRRV	- On Peak		17.132
42		- Off Peak		12.642
43	HRRV	- On Peak	(excess)	0.000
44		- Off Peak	(excess)	12.642
45	Chevron	- On Peak		20.440
46		- Off Peak		14.990
47	Hoku Solar			19.000
48	Kalaeloa			14.992
49	AES-HI			2.869
	PURCHASED ENERGY KWH MIX, %			
50	THC	- On Peak		0.07
51		- Off Peak		0.05
52	HRRV	- On Peak		5.76
53		- Off Peak		2.60
54	HRRV	- On Peak	(excess)	0.00
55		- Off Peak	(excess)	1.52
56	Chevron	- On Peak		0.01
57		- Off Peak		0.01
58	Hoku Solar			0.01
59	Kalaeloa			44.25
60	AES-HI			45.72
61	COMPOSITE COST OF PURCHASED ENERGY, ¢/KWH			9.481
62	% Input to System kWh Mix			41.54
63	WTD CMP PURCH ENRGY COST, ¢/KWH (Line x 61)			$\boxed{3.93841}$
64	BASE PURCH ENERGY COMP COST			9.481
65	Base % Input to System kWh Mix			41.54
66	WTD BASE PRCH ENERGY COST, ¢/KWH (Line 64 x 65)			$\boxed{3.93841}$
67	Cost Less Base (Line 63 - 66)			0.00000
68	Loss Factor			1.052
69	Revenue Tax Req Multiplier			1.0975
70	PURCHASED ENERGY FACTOR, ¢/KWH (Line 67 x 68 x 69)			0.00000

Line	**SYSTEM COMPOSITE**	
71	Total Generation and Purchased Energy Factor, ¢/kWh (Line 38 + 70)	0.00000
72	Adjustment, ¢/kWh	**0.000**
73	ECA Reconciliation Adjustment, ¢/kWh	0.000
74	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH (Line 71 + 72 + 73)	0.000

		Loss Factor	Rev.Tax.Mult.	Gross
WEIGHTED BASE GEN COST,	10.56579	1.0000	1.0975	11.59595
WTD BASE DG ENERGY COST,	0.01750	1.0520	1.0975	0.02020
WTD BASE PRCH ENERGY COST,	3.93841	1.0520	1.0975	4.54717
TOTAL	14.52170			16.16333
WEIGHTED COMPOSITE GEN COST,	10.56579	1.0000	1.0975	11.59595
WTD COMP DG ENRGY COST,	0.01750	1.0520	1.0975	0.02020
WTD CMP PURCH ENRGY COST,	3.93841	1.0520	1.0975	4.54717
TOTAL	14.52170			16.16333

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Hawaiian Electric Company

Fuel Oil Adjustment Reconciliation Summary

Annual Reconciliation (Thousand $)

Direct Case As Test Year and Direct Case As Following Year w/Existing ECAC and Reconciliatior

Line			Total	Weighted Cost per kWh	Sales	Utility Generation Fuel Price	Utility Generation Gen. Mix	Heat Rate	Purchased Energy Price	Purchased Energy Purch. Mix	Dist.Generation Price	Gen/Puch/DG Fraction
A	Annual Sales Volume	Direct =>	7657.8		Direct =>	7657.8						
X	Purchased Power Volume	Direct =>	3345.6		Direct =>	3345.6						
					Assumed Parameters							
	ACTUAL COSTS (PER ECAC NET OF REV.TAXES)											
1	Generation		809,107	10.5658	Direct	Direct	Direct	Direct				Direct
2	Purch Power		317,196	4.1421	Direct				Direct	Direct		Direct
3	DG Power		1,340	0.0175	Direct						Direct	Direct
4	Total		1,127,644	14.7254								
	FUEL FILING COST (CALCULATED REVENUES)											
5	Generation		809,107	10.5658	Direct	Direct	Direct	Direct				Direct
6	Purch Power		317,196	4.1421	Direct				Direct	Direct		Direct
7	DG Power		1,340	0.0175	Direct						Direct	Direct
8	Total		1,127,644	14.7254								
	BASE FUEL COST (REVENUES IN BASE RATES)											
9	Generation		809,107	10.5658	Direct	Direct	Direct	Direct				Direct
10	Purch Power		317,196	4.1421	Direct				Direct	Direct		Direct
Z	DG Power		1,340	0.0175	Direct						Direct	Direct
11	TOTAL		1,127,644	14.7254								
12	FUEL-BASE COST (ECAC TARGET ADJUST)	Lines 8 -11	0	0.0000								
B	Generation		0	0.0000								
C	Purch Power		0	0.0000								
D	DG Power		0	0.0000								
13	ACTUAL FOA LESS TAX		0	0.0000								
14	FOA reconciliation adj for prior year		0									
15	ADJUSTED FOA LESS TAX		0	0.0000								
16	FOA-(FUEL-BASE)	Lines 15-12	0									
	ADJUSTMENTS											
17												
18	Current month's FOA Adjustment in line 14		0									
19	DG Fuel & Trucking		0									
20	QUARTERLY FOA RECONCILIATION	Lines 14-15+16-17	0	0.0000								
	RECONCILED REVENUES (BASE PLUS ECAC ADJUST)											
E	Generation	Lines 9+B	809,107	10.5658								
F	Purch Power	Lines 10+C	317,196	4.1421								
G	DG Power	Lines 11+D	1,340	0.0175								
H	TOTAL	Lines 11+12	1,127,644	14.7254								
	RECONCILED REVENUES MINUS ACTUAL COSTS											
I	Generation	Lines E - 1	0	0.0000								
J	Purch Power	Lines F - 2	0	0.0000								
K	DG Power	Lines G - 3	0	0.0000								
L	TOTAL	Lines H - 4	0	0.0000								

Hawaiian Electric Company, Inc.
ENERGY COST ADJUSTMENT FILING
Update Case As Year Following Test Year at Test Year Rates

Line			
1	**Effective Date**	2009 Test Year - Update	
2	**Supercedes Factor**		
	GENERATION COMPONENT		
	FUEL PRICES, ¢/MBTU		
3	Honolulu	1,652.16	
4	Kahe	1,602.36	
5	Waiau-Steam	1,602.06	
6	Waiau-Waste	**0.00**	
7	Waiau-Diesel	2,366.04	
8	CIP-Diesel	2,402.08	
9	CIP-Biodiesel	**4,643.68**	4643.68
			4602.67
	BTU MIX, %		
10	Honolulu	**3.82**	
11	Kahe	**70.28**	
12	Waiau-Steam	**24.74**	
13	Waiau-Waste	**0.00**	
14	Waiau-Diesel	**0.41**	
15	CIP-Diesel	**0.70**	
16	CIP-Biodiesel	**0.05**	
		100.00	
17	COMPOSITE COST OF GENERATION, ¢/MBTU	1,614.44	
18	% Input to system kWh Mix	**57.57**	
19	Efficiency Factor, Mbtu/kWh	**0.011185**	
20	WEIGHTED COMPOSITE GEN COST, ¢/KWH (Line 17 x 18 x 19)	$\boxed{10.39571}$	18.06
21	BASE GENERATION COST, ¢/Mbtu	**1,617.81**	
22	Base % Input to System kWh Mix	58.39	
23	Efficiency Factor, Mbtu/kWh	**0.011185**	
24	WEIGHTED BASE GEN COST, ¢/KWH (Line 21 x 22 x 23)	10.56579	18.10
25	Cost Less Base (Line 20 - 24)	(0.17008)	
26	Revenue Tax Req Multiplier	1.0975	
27	GENERATION FACTOR, ¢/KWH (Line 25 x 26)	(0.18666)	
	DG ENERGY COMPONENT		
28	COMPOSITE COST OF DG ENERGY, ¢/kWh	24.99	
29	% Input to System kWh Mix	**0.05**	
30	WTD COMP DG ENRGY COST, ¢/KWH (Line 28 x 29)	$\boxed{0.01250}$	25.00
31	BASE DG ENERGY COMP COST	24.993	
32	Base % Input to System kWh Mix	0.07	
33	WTD BASE DG ENERGY COST, ¢/KWH (Line 31 x 32)	0.01750	25.00
34	Cost Less Base (Line 30 - 33)	(0.00500)	
35	Loss Factor	1.051	
36	Revenue Tax Req Multiplier	1.0975	
37	DG FACTOR, ¢/KWH (Line 34 x 35 x 36)	(0.00577)	
38	TOTAL GENERATION FACTOR ¢/KWH (Line 27 + 37)	(0.19243)	

Line					
	PURCHASED ENERGY COMPONENT				
	PURCHASED ENERGY PRICE - ¢/KWH				
39	THC	- On Peak		**19.826**
40		- Off Peak		**15.088**
41	HRRV	- On Peak		**16.672**
42		- Off Peak		**12.716**
43	HRRV	- On Peak	(excess)	0.000
44		- Off Peak	(excess)	**12.716**
45	Chevron	- On Peak		**19.826**
46		- Off Peak		**15.088**
47	Hoku Solar			**19.000**
48	Kalaeloa			**14.995**
49	AES-HI			**2.873**
	PURCHASED ENERGY KWH MIX, %			
50	THC	- On Peak		**0.07**
51		- Off Peak		**0.05**
52	HRRV	- On Peak		**5.79**
53		- Off Peak		**2.61**
54	HRRV	- On Peak	(excess)	**0.00**
55		- Off Peak	(excess)	**1.52**
56	Chevron	- On Peak		**0.01**
57		- Off Peak		**0.01**
58	Hoku Solar			**0.01**
59	Kalaeloa			**44.08**
60	AES-HI			**45.85**
61	COMPOSITE COST OF PURCHASED ENERGY, ¢/KWH			9.444
62	% Input to System kWh Mix			**42.38**
63	WTD CMP PURCH ENRGY COST, ¢/KWH (Line x 61)			$\boxed{4.00237}$
64	BASE PURCH ENERGY COMP COST			9.481
65	Base % Input to System kWh Mix			41.54
66	WTD BASE PRCH ENERGY COST, ¢/KWH (Line 64 x 65)			3.93841
67	Cost Less Base (Line 63 - 66)			0.06396
68	Loss Factor			1.051
69	Revenue Tax Req Multiplier			1.0975
70	PURCHASED ENERGY FACTOR, ¢/KWH (Line 67 x 68 x 69)			0.07378

Line	**SYSTEM COMPOSITE**	
71	Total Generation and Purchased Energy Factor, ¢/kWh (Line 38 + 70)	(0.11865)
72	Adjustment, ¢/kWh	**0.000**
73	ECA Reconciliation Adjustment, ¢/kWh	0.000
74	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH (Line 71 + 72 + 73)	(0.119)

	wcpkWh	% Mix	Loss Factor	Rev.Tax.Mult.	Gross
WEIGHTED BASE GEN COST,	10.56579	58.39	1.0000	1.0975	11.59595
WTD BASE DG ENERGY COST,	0.01750	0.07	1.0520	1.0975	0.02020
WTD BASE PRCH ENERGY COST,	3.93841	41.54	1.0520	1.0975	4.54717
TOTAL	14.52170	100.00			16.16333

WEIGHTED COMPOSITE GEN COST,	10.39571	57.57	1.0000	1.0975	11.40929
WTD COMP DG ENRGY COST,	0.01250	0.05	1.0520	1.0975	0.01443
WTD CMP PURCH ENRGY COST,	4.00237	42.38	1.0520	1.0975	4.62102
TOTAL	14.41058	100.00			16.04474

Hawaiian Electric Company, Inc.
ENERGY COST ADJUSTMENT FILING
Update Case As Year Following Test Year at Update Case Heat Rate

Line		
1	**Effective Date**	
2	**Supercedes Factor**	
	GENERATION COMPONENT	
	FUEL PRICES, ¢/MBTU	
3	Honolulu	1,652.16
4	Kahe	1,602.36
5	Waiau-Steam	1,602.06
6	Waiau-Waste	0.00
7	Waiau-Diesel	2,366.04
8	CIP-Diesel	2,402.08
9	CIP-Biodiesel	4,643.68
	BTU MIX, %	
10	Honolulu	3.82
11	Kahe	70.28
12	Waiau-Steam	24.74
13	Waiau-Waste	0.00
14	Waiau-Diesel	0.41
15	CIP-Diesel	0.70
16	CIP-Biodiesel	0.05
		100.00
17	COMPOSITE COST OF GENERATION, ¢/MBTU	1,614.44
18	% Input to system kWh Mix	57.57
19	Efficiency Factor, Mbtu/kWh	0.011166
20	WEIGHTED COMPOSITE GEN COST, ¢/KWH (Line 17 x 18 x 19)	10.37805
21	BASE GENERATION COST, ¢/Mbtu	1,617.60
22	Base % Input to System kWh Mix	58.39
23	Efficiency Factor, Mbtu/kWh	0.011185
24	WEIGHTED BASE GEN COST, ¢/KWH (Line 21 x 22 x 23)	10.56442
25	Cost Less Base (Line 20 - 24)	(0.18637)
26	Revenue Tax Req Multiplier	1.0975
27	GENERATION FACTOR, ¢/KWH (Line 25 x 26)	(0.20454)
	DG ENERGY COMPONENT	
28	COMPOSITE COST OF DG ENERGY, ¢/kWh	24.99
29	% Input to System kWh Mix	0.05
30	WTD COMP DG ENRGY COST, ¢/KWH (Line 28 x 29)	0.01250
31	BASE DG ENERGY COMP COST	24.993
32	Base % Input to System kWh Mix	0.07
33	WTD BASE DG ENERGY COST, ¢/KWH (Line 31 x 32)	0.01750
34	Cost Less Base (Line 30 - 33)	(0.00500)
35	Loss Factor	1.052
36	Revenue Tax Req Multiplier	1.0975
37	DG FACTOR, ¢/KWH (Line 34 x 35 x 36)	(0.00577)
38	TOTAL GENERATION FACTOR ¢/KWH (Line 27 + 37)	(0.21031)

Line				
	PURCHASED ENERGY COMPONENT			
	PURCHASED ENERGY PRICE - ¢/KWH			
39	THC	- On Peak		19.826
40		- Off Peak		15.088
41	HRRV	- On Peak		16.672
42		- Off Peak		12.716
43	HRRV	- On Peak	(excess)	0.000
44		- Off Peak	(excess)	12.716
45	Chevron	- On Peak		19.826
46		- Off Peak		15.088
47	Hoku Solar			19.000
48	Kalaeloa			14.995
49	AES-HI			2.873
	PURCHASED ENERGY KWH MIX, %			
50	THC	- On Peak		0.07
51		- Off Peak		0.05
52	HRRV	- On Peak		5.79
53		- Off Peak		2.61
54	HRRV	- On Peak	(excess)	0.00
55		- Off Peak	(excess)	1.52
56	Chevron	- On Peak		0.01
57		- Off Peak		0.01
58	Hoku Solar			0.01
59	Kalaeloa			44.08
60	AES-HI			45.85
61	COMPOSITE COST OF PURCHASED ENERGY, ¢/KWH			9.444
62	% Input to System kWh Mix			42.38
63	WTD CMP PURCH ENRGY COST, ¢/KWH (Line x 61)			4.00237
64	BASE PURCH ENERGY COMP COST			9.444
65	Base % Input to System kWh Mix			41.54
66	WTD BASE PRCH ENERGY COST, ¢/KWH (Line 64 x 65)			3.92304
67	Cost Less Base (Line 63 - 66)			0.07933
68	Loss Factor			1.052
69	Revenue Tax Req Multiplier			1.0975
70	PURCHASED ENERGY FACTOR, ¢/KWH (Line 67 x 68 x 69)			0.09159

Line	**SYSTEM COMPOSITE**	
71	Total Generation and Purchased Energy Factor, ¢/kWh (Line 38 + 70)	(0.11872)
72	Adjustment, ¢/kWh	0.000
73	ECA Reconciliation Adjustment, ¢/kWh	0.000
74	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH (Line 71 + 72 + 73)	(0.119)

		Loss Factor	Rev.Tax.Mult.	Gross
WEIGHTED BASE GEN COST,	10.56442	1.0000	1.0975	11.59445
WTD BASE DG ENERGY COST,	0.01750	1.0520	1.0975	0.02020
WTD BASE PRCH ENERGY COST,	3.92304	1.0520	1.0975	4.52942
TOTAL	14.50496			16.14408
WEIGHTED COMPOSITE GEN COST,	10.37805	1.0000	1.0975	11.38991
WTD COMP DG ENRGY COST,	0.01250	1.0520	1.0975	0.01443
WTD CMP PURCH ENRGY COST,	4.00237	1.0520	1.0975	4.62102
TOTAL	14.39292			16.02536

Hawaiian Electric Company
Fuel Oil Adjustment Reconciliation Summary
Annual Reconciliation (Thousand $)

Direct Case As Test Year and Update Case As Following Year w/Existing ECAC and Reconciliation

Line			Total	Weighted Cost per kWh	Sales	Utility Generation Fuel Price	Utility Generation Gen. Mix	Heat Rate	Purchased Energy Price	Purchased Energy Purch. Mix	Dist.Generation Price	Gen/Puch/DG Fraction
A	Annual Sales Volume	Update =>	7484.7		Direct =>	7657.8						
X	Purchased Power Volume	Update =>	3335.8		Direct =>	3345.6						
					Assumed Parameters							
	ACTUAL COSTS (PER ECAC NET OF REV.TAXES)											
1	Generation		776,766	10.3781	Update	Direct	Update	Update				Update
2	*Purch Power*		*315,033*	*4.2090*	*Update*				*Update*	*Update*		*Update*
3	DG Power		936	0.0125	Update						Identical	Update
4	Total		1,092,734	14.5996								
	FUEL FILING COST (CALCULATED REVENUES)											
5	Generation		778,088	10.3957	Update	Direct	Update	Direct				Update
6	Purch Power		315,033	4.2090	Update				Update	Update		Update
7	DG Power		936	0.0125	Update						Identical	Update
8	Total		1,094,056	14.6172								
	BASE FUEL COST (REVENUES IN BASE RATES)											
9	Generation		790,818	10.5658	Update	Direct	Direct	Direct				Direct
10	Purch Power		310,026	4.1421	Update				Direct	Direct		Direct
Z	DG Power		1,310	0.0175	Update						Identical	Direct
11	TOTAL		1,102,154	14.7254								
12	FUEL-BASE COST (ECAC TARGET ADJUST)	Lines 8 -11	$\boxed{-8,098}$	-0.1082								
B	Generation		-12,730	-0.1701								
C	Purch Power		5,007	0.0669								
D	DG Power		-374	-0.0050								
13	ACTUAL FOA LESS TAX		-8,279	-0.1106								
14	FOA reconciliation adj for prior year		0									
15	ADJUSTED FOA LESS TAX		-8,279	-0.1106								
16	FOA-(FUEL-BASE)	Lines 15-12	181									
	ADJUSTMENTS											
17												
18	Current month's FOA Adjustment in line 14		0									
19	DG Fuel & Trucking		0									
20	QUARTERLY FOA RECONCILIATION	Lines 14-15+16-17	181	0.0024								
	RECONCILED REVENUES (BASE PLUS ECAC ADJUST)											
E	Generation	Lines 9+B	778,088	10.3957								
F	Purch Power	Lines 10+C	315,033	4.2090								
G	DG Power	Lines 11+D	936	0.0125								
H	TOTAL	Lines 11+12	1,094,056	14.6172								
	RECONCILED REVENUES MINUS ACTUAL COSTS											
I	Generation	Lines E - 1	1,322	0.0177								
J	Purch Power	Lines F - 2	0	0.0000								
K	DG Power	Lines G - 3	0	0.0000								
L	TOTAL	Lines H - 4	1,322	0.0177								

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that I have, by May 11. 2009, served a copy of the foregoing HAIKU DESIGN AND ANALYSIS FINAL STATEMENT OF POSITION upon the following entities, by first class mail or by electronic transmission as noted:

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Dated: May 9, 2009; Haiku, Hawaii

Signed: CARL FREEDMAN
Carl Freedman